NON-PUBLIC?: N
ACCESSION #: 8912260017
LICENSEE EVENT REPORT (LER)

FACILITY NAME: SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 3
PAGE: 1 OF 08

DOCKET NUMBER: 05000362

TITLE: REACTOR TRIP ON LOW STEAM GENERATOR LEVEL DUE TO PARTIAL LOSS OF
POWER TO FEEDWATER CONTROL SYSTEM
EVENT DATE: 01/06/89 LER #: 89-001-03 REPORT DATE: 12/15/89

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: H. E. Morgan TELEPHONE: (714)368-6241

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: EE COMPONENT: XFMR MANUFACTURER: S250
REPORTABLE NPRDS: Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

At 2335 on 1/6/89, with Unit 3 at 98% power, the reactor tripped on low steam generator (SG) level after a partial loss of non-1E Uninterruptible Power Supply (UPS) power occurred which caused feedwater regulating valves to reduce flow to SG E089. This also resulted in actuation of emergency feedwater to SG E089. Emergency feedwater to SG E088 also actuated due to the resulting level "shrink" in SG E088, which is expected following a trip from high power. Since the Steam Bypass Control System was in manual to perform turbine valve testing, heat removal from the SGs was greater than normal. At 2336, as a result of the lower SG temperature, reactor coolant system (RCS) pressure decreased below the Safety Injection Actuation Signal (SIAS) setpoint (1806 psia), resulting in an SIAS actuation. There was no safety injection flow into the RCS since RCS pressure remained above the shutoff head of the

injection pumps. All safety systems operated in accordance with design. At 0025 on 1/7/89, the plant was stabilized and all Engineered Safety Features were reset and lineups returned to normal.

Two of three non-1E UPS phases were lost because of a common fault in the associated inverter's constant voltage transformer (CVT) output windings. A temporary jumper, which had not been properly removed during previous maintenance, was found between UPS ungrounded neutral and ground. There were two prior failures of a CVT in the same inverter after the installation of the temporary jumper, but neither resulted in a safety system actuation. The cause of the transformer failure was the breakdown of insulation between the energized windings and the grounded iron core. Extensive analysis of the failed transformer was unable to determine a root cause for the transformer insulation breakdown. However, with the jumper installed, it is believed that the development of a fault or ground in the transformer created a current path which bypassed the installed ground detection system and caused severe damage to the transformer.

As corrective actions, the jumper was removed, the CVTs were replaced, and the non-1E UPS was satisfactorily tested. The cause of the event was reviewed with applicable personnel and appropriate disciplinary action was taken.

END OF ABSTRACT

Plant: San Onofre Nuclear Generating Station
Unit: Three
Reactor Vendor: Combustion Engineering
Event Date: 1-6-89
Time: 2335

A. CONDITIONS AT TIME OF THE EVENT:

Mode: 1, Power Operation

B. BACKGROUND INFORMATION:

The steam generator SG! low level reactor trip provides protection for a loss of feedwater accident and assures that the design pressure of the Reactor Coolant System (RCS) AB! will not be exceeded due to loss of SG heat removal. The trip setpoint ensures that SG water inventory is sufficient such that the RCS will be cooled during start of the emergency feedwater system BA). A SG low level trip is initiated by any two-out-of-four independent level channels associated with either of two SG (E088 and E089). In addition, the Emergency Feedwater Actuation System (EFAS) associated with a SG (EFAS #1 for E089 and EFAS #2 for E088) is initiated at the low level trip setpoint for that SG.

The Feedwater Control System (FWCS) JB! regulates feedwater flow to the SGs by positioning feedwater control valves FCV! and changing main feed water pump MFWP! speed in order to maintain SG level and replenish inventory removed as steam. Following a reactor trip or loss of power to the FWCS, the FWCS reduces feedwater flow to that necessary for initial latent heat removal by positioning the feedwater control valves to a preset, reduced flow, position.

Power is supplied to the FWCS from a non-safety related (non-1E) 120 VAC Uninterruptible Power Supply (UPS), EE!. The UPS is supplied by an inverter INVT!, or by an alternate 480 VAC source via a regulator 90! through automatic switching ASU!. The UPS provides 3 phase (A, B and C) power connected in a "Y" configuration with an ungrounded neutral. The inverter produces the 3 phase 120 VAC power in synchronization and phase with the alternate power source using two inverter (chopping) bridges and a constant voltage transformer (CVT) XFMR!. The CVT consists of two main core transformers, which have dissimilar secondary windings and filter assemblies, which produce the correct 3 phase relationship to neutral. Control circuits provide voltage regulation and frequency control under varying loads, and synchronization to the alternate source.

C. DESCRIPTION OF THE EVENT:

1. Event:

At 2335 on January 6, 1989, with Unit 3 at 98% power, during the performance of weekly turbine valve testing, a partial loss of non-1E UPS power (phases B and C) occurred, which caused the FWCS to position the SG E089 feedwater valves to their post-trip, reduced flow position. This resulted in a decrease in SG E089 level, which led to actuations of both the Reactor Protection System (RPS) JC! and EFAS #1 on low level in SG E089. EFAS #2 also actuated due to the resulting level "shrink" in SG E088, which is expected following a trip from high power.

The Steam Bypass Control System (SBCS)JI), which directs steam directly to the condenser (bypassing the main turbine) while maintaining SG pressure at a prescribed setpoint, had been manually set to perform turbine stop valve testing in accordance with procedures. Thus, following the reactor trip, the SBCS operated to maintain SG pressure approximately 100 psi below that which is normal. At 2336, as a result of the lower SG temperature (due to lower pressure), RCS pressure decreased below the Safety Injection Actuation Signal (SIAS) setpoint (1806 psia), resulting in an SIAS actuation. As per design, the SIAS initiated Containment Cooling Actuation Signal (CCAS) BK! and Control Room Isolation Signal (CRIS) VI! actuations.

The minimum RCS pressure reached during the transient (1717 psia) was greater than the shutoff head of the High Pressure Safety Injection (HPSI) pumps BQ!P!; therefore, no injection flow reached the RCS. The plant was stabilized and all Engineered Safety Features (ESF) were reset and lineups returned to normal at 0025 on January 7, 1989.

2. Inoperable Structures, Systems or Components that Contributed to the Event:

None.

3. Sequence of Events:

DATE TIME ACTION

1/6/89 2015 Operators commenced turbine valve testing
and placed SBCS in manual.

1/6/89 2335 Partial loss of power occurred to non-1E
UPS. Reactor tripped due to low level in
SG E089. EFAS initiated.

1/6/89 2336 SIAS initiated due to low RCS pressure.
CCAS and CRIS initiated from the SIAS.

1/6/89 2338 RCS pressure begins to stabilize from a low
of 1717 psia.

1/7/89 0025 SIAS, CCAS and CRIS reset and alignment
returned to normal. EFAS reset with manual
control of feedwater. Operators complete

Standard Post-Trip Actions and Reactor Trip Recovery procedures.

1/9/89 0525 Entered Mode 1 for Unit return to service.

4. Method of Discovery:

Control room alarms and indications alerted the operators of the reactor trip.

5. Personnel Actions and Analysis of Actions:

The operators responded properly to the reactor trip and stabilized plant conditions utilizing the Standard Post-Trip Actions and the Reactor Trip Recovery procedures.

The operators also responded properly by verifying that all EFAS, SIAS, CCAS, and CRIS components actuated as required.

6. Safety System Responses:

The RPS and EFAS operated in accordance with design, with no malfunctions noted. SIAS, CCAS and CRIS, which actuated in response to the low RCS pressure, also operated in accordance with design. Additional information regarding safety system responses are described below:

Post-trip review of plant computer data revealed that SG E089 low level trip channels 1 and 4 initiated 1.4 and 0.4 seconds, respectively, after the reactor trip signal had been generated by channels 2 and 3. This response is considered normal; nonetheless, the level sensing lines were flushed, and no blockage or foreign material was found. This pattern of level response is indicative of the hydrodynamic effects which occur in the level sensing region of a SG when feedwater or steam flow are rapidly reduced. This was previously reported in LER 87-004-01 (Docket No. 50-361).

The HPSI discharge lines were pressurized to a maximum recorded value of 1556 psia. The pressure in one discharge line did not decrease as expected following securing the HPSI pumps. This has been attributed to a slight amount of RCS leakage into the discharge line due to reduced sealing force on the associated injection check valve V!. RCS pressure reached its lowest value of 1717 psia and the HPSI discharge lines were pressurized to a maximum recorded value of 1556 psia; thus, the differential pressure across the injection check valve (potentially as low as 161 psid) was significantly less than the normal value of 1250 psid, resulting in less check valve sealing. Normal check valve sealing was restored when RCS

pressure was returned to 2250 psia and the associated HPSI discharge line pressure was lowered to about 700 psia. Full resealing was achieved after the proper pressure differential was applied to the valve, in accordance with valve design.

Minor equipment anomalies observed following the reactor trip included: 1) one of two Nuclear Instrumentation Log Power indicators JI! did not completely trend with decreasing reactor power at its lower range; and 2) an alarm indicating lamp IL! to one of four Core Protection Calculator channels did not illuminate. Neither of these anomalies were significant since they did not affect operability of any safety systems or the course of operator actions during this event. Corrective action was taken prior to returning the unit to service by recalibrating the Log Power channel indicator and replacing the failed lamp.

D. CAUSE OF THE EVENT:

1. Immediate Cause:

The FWCS positioned the SG E089 feedwater control valves to their post-trip, reduced flow positions, due to loss of non-1E UPS phases B and C. Both phases were lost because of a common fault in the associated inverter's CVT main core transformer output windings.

The immediate cause of the transformer failure was the breakdown of insulation between the energized windings and the grounded iron core.

2. Contributing Cause: Investigation following the trip identified an installed jumper between UPS ungrounded neutral and ground, which had been erroneously left in place following maintenance. The jumper was installed by two maintenance technicians (non-utility, non-licensed) on 6/15/88, during installation of temporary power to supply certain non-1E loads during maintenance of connections associated with the non-1E UPS. Although the temporary power cables were properly installed and

documented in accordance with the procedure governing temporary system alterations, the te
hnicians did not document in the work package the Jumper installation contrary to this procedure. As a result, another technician (utility, non-licensed), who removed the temporary power, was not prompted to remove the jumper upon finishing the work.

3. Root Cause:

Extensive analysis of the failed transformer was unable to determine a root cause for the transformer insulation break down. However, with the jumper installed, it is believed that the development of a fault or ground in the transformer created a current path which bypassed the installed ground detection system and caused severe damage to the transformer. This conclusion is supported by the fact that since installation of the jumper

in June 1988, two transformer failures occurred prior to the failure being reported in this LER (See Section G.3 for additional discussion). Prior to installation of the jumper, no transformer failures of this type had occurred.

The failure analysis that was performed included nondestructive and destructive testing of the failed transformer. Since the damage to the transformer was sufficiently severe such that any pre-existing condition leading to the insulation breakdown was obscured, this analysis did not provide a root cause for the failure. Additionally, an examination of a non-faulted transformer did not result in the identification of a failure mechanism. The existence of contamination (e.g. dirt, moisture, oil, etc.) of the transformer windings was evaluated and determined not to be a cause of the failure. An engineering analysis did not identify any atypical effects that a neutral ground could have on the transformer controls. The transformer manufacturer did not identify any manufacturing or design deficiencies with the product. The manufacturer also stated that the inverter design was such that it could be operated with either a grounded or ungrounded neutral with no adverse effect on the inverter, and in fact, similar inverters are operated with a grounded neutral at other facilities. The manufacturer was not aware of any electrical phenomenon which could result in the transformer failures due to the installation of the jumper.

SCE has concluded that the jumper did not cause the initial breakdown of insulation leading to the fault, but it is clear that once a transformer ground fault occurred, the jumper provided a return path for the ground fault current. With a low impedance return path established, the fault current was of sufficient magnitude to severely damage the transformer. Because the location of the fault was internal to the inverter, and a neutral-to-ground return path was established by the jumper, the inverter and UPS system protective devices were rendered useless to detect this fault condition. The ground detection system installed on the Non-1E UPS system is designed to detect grounds without the jumper installed.

E. CORRECTIVE ACTIONS:

1. Corrective Actions Taken:

a. The jumper was removed and the CVT main core transformers were replaced. Prior to returning Unit 3 to service, the inverter and non-1E UPS were tested and found to be operational. With the unauthorized jumper removed, the development of future ground conditions within the transformer will be detected by the installed ground detection system prior to catastrophic failure of the Non-1E UPS.

b. This event has been reviewed with the technicians who had installed the jumper and appropriate disciplinary action has been taken.

c. This event has been reviewed with all appropriate maintenance personnel, emphasizing the importance of properly following the governing procedure for the use and control of temporary jumpers.

d. Although no deficiencies with the procedure for temporary system alterations and restorations were identified by a review conducted prior to Revision 0 of this LER, this procedure has been further reviewed and it has been determined that enhancements are not needed.

e. The operations procedure, which priortizes corrective and preventive maintenance, was revised to require that a "MANDATORY" (Priority 2) priority be assigned to any repair required due to AC or DC grounds on Important to Safety circuits.

F. SAFETY SIGNIFICANCE OF THE EVENT:

There was no safety significance associated with the reactor trip since all safety and protective systems actuated by the RPS, SIAS, CCAS, CRIS, and EFAS #s 1 and 2 operated in accordance with their design.

G. ADDITIONAL INFORMATION:

1. Component Failure Information:

The inverter is a 217-290 VDC to 120/208 VAC, 3 phase, 60 Hz, 150 KVA unit, manufactured by Solid State Controls Incorporated under part list number 23778. A CVT main core transformer (item number TX801, part number 312744) is known to have failed.

2. Previous LERs on Similar Events (LER 3-87-011-02):

On 6/21/87 at 0258, with Unit 3 in Mode 1 at 100% power, the reactor automatically tripped on low SG water level. The low SG level was caused by an intermittent loss of power in one phase of a 120 VAC non-1E Instrument Bus which resulted in the inability to control feedwater and the consequent reduction in SG level. The loss of power was caused by a loose bolt connecting the B phase of instrument power to the main power bus of the non-1E UPS. The loose connection was corrected by tightening the bolt. The cause and corrective actions associated with that event are not applicable to the loss of the UPS phase B and C power on 1/6/89.

3. Previous investigations of Non-1E UPS Inverter:

On 7/2/88, maintenance technicians missed discovering the jumper, which was connected to the Non-1E UPS system down stream of the inverter during the first replacement of the transformer, which had failed due to overheating. The jumper may have contributed to this failure as well. The presence of the jumper was not observed, because replacement of the inverter did not include a detailed verification of Non-1E UPS system connections down stream of the inverter. The jumper was in an electrical distribution panel located in another room approximately 500 feet from the inverter.

In addition, on 10/23/88, during the second replacement of the transformer, trouble shooting efforts were increased and included a check of the Non-1E UPS system down stream of the inverter. A maintenance technician identified the presence of a neutral ground by meter reading. At this time, there was no direct observation of the jumper, because the jumper was neatly ty-wrapped to existing cables in the panel and it was not readily apparent that the jumper was meant to be a temporary connection. The technician requested a maintenance order to investigate the ground. This equipment is non-safety related and in accordance with procedure, maintenance was planned and given appropriate priority. Since the presence of a neutral ground does not render the inverter nonfunctional, the maintenance order was given a priority which would ensure that the problem was corrected within an appropriate period of time and when plant conditions permitted. However, 2 months later, the CVT main core transformer failed for the third time (resulting in the event being reported herein), prior to removal of the jumper. As corrective action, this event, including the missed opportunities to discover the jumper, has been reviewed with appropriate maintenance personnel.

ATTACHMENT 1 TO 8912260014 PAGE 1 OF 1

Southem California Edison Company

SAN ONOFRE NUCLEAR GENERATING STATION

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STATION MANAGER December 15, 1989 (714) 368-6241

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Subject: Docket No. 50-362
Supplemental Report
Licensee Event Report No. 89-001, Revision 3
San Onofre Nuclear Generating Station, Unit 3

Reference: Letter, H. E. Morgan (SCE) to USNRC Document Control Desk, dated July 14, 1989

The referenced letter provided Licensee Event Report (LER) No. 89-001, Revision 2 for an occurrence involving the Non-1E Uninterruptible Power Supply system. The enclosed supplemental LER provides additional information concerning the cause and corrective actions. Neither the health and safety of plant personnel or the public was affected by this occurrence.

If you require any additional information, please so advise.

Sincerely,

Enclosure: LER No. 89-001, Revision 3

cc: C. W. Caldwell (USNRC Senior Resident Inspector, Units 1, 2 and 3)
J. B. Martin (Regional Administrator, USNRC Region V)
Institute of Nu
lear Power Operations (INPO)

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